NATURAL GAS CONSTRAINTS WORKSHOP SUMMARY

INTRODUCTION

On January 25, 2001, the California Energy Commission (Energy Commission) conducted the Natural Gas Constraints Workshop to identify and discuss natural gas supply constraint issues that may affect the licensing of future power plants by the Energy Commission. Issues discussed included: (1) inter- and intra-state gas pipeline capacity; and (2) current natural gas utility curtailment policies/procedures. The purpose of the workshop was to obtain the information needed to develop appropriate actions, if any, to avoid natural gas supply constraints to the licensing of future power plants.

OVERVIEW OF ORAL PRESENTATION

In opening comments, Commissioners Laurie and Pernell explained the purpose of the workshop was to gather as much information as possible on natural gas supply constraints that may affect the Energy Commission's processing of Applications for the Certification of future power plants.

At the beginning of the workshop, Bill Wood, representing Energy Commission staff, summarized the staff's overview paper "Natural Gas Issues That May Affect Siting New Power Plants in California", January 11, 2000. Mr. Wood concluded that while natural gas resources in the U. S. and Canada are adequate to meet California's future needs, the current capacity of reliable gas transmission to meet California's growing gas consumption is questionable. Current inter-state transmission is at a 91% capacity factor, leaving very little space to get gas into seasonal storage facilities that provide for peak gas demand during both winter and summer. Current inter-state transmission capacity is also competing with a growing demand for gas for power plants being built in the states surrounding California, some drawing their gas directly from inter-state transmission pipelines, further constraining downstream capacity.

Traditionally, the inter-state and intra-state transmission pipeline system was developed to meet peak core customer demand, with non-core customers having the capability to switch to alternate fuels. Increasingly, air quality requirements have eliminated the use of alternate fuels, leaving non-core customers, such as power plants, subject to being curtailed and reducing operational levels during peak gas demand periods. This leads to the question of whether curtailment rules should be changed to include the gas requirements of power plants as firm demand. This would significantly increase the future capacity needs of both the inter- and intra-state gas transmission systems. Some relief could be provided by increasing California in-state gas production and by providing ways to use alternate fuels that would meet air quality requirements.

PANEL 1: INTER- AND INTRA-STATE GAS PIPELINE CAPACITY

Kirk Morgan, Kern River Gas Transmission Co., Director, Business Development

The Kern River Gas Transmission Co. supplies California with about 700 million cubic feet per day (MMcf/d), or about ten-percent of the state's total supply. Two expansions, in 2002 and 2003, are planned for meeting new power plant requirements in California and Nevada. These expansions will access increased Rocky Mountain production. A number of competing power plants are proposed by the same sponsors, both upstream of California and in California, leading to the question of whether upstream plants will use pipeline gas and export power to California or whether California will get the gas for new in-state power plants that will contribute to power generation self-sufficiency within California. The current tightness in gas supply capacity would require the expansion of the main pipeline from the Rocky Mountains if a large number of currently proposed power plants were to be built. However, because there are also capacity limitations on the intra-state pipelines, delivery capacity limitations can't be solved with upstream expansion alone. Expanded access to SoCal Gas, in particular at Wheeler Ridge, and at new receipt points, e.g. Adelanto, should be considered. The cost, efficiency, and reliability tradeoffs of electricity vs. gas for transmission pipeline compression was also presented.

Eric Eisenmann, Pacific Gas Transmission Northwest (GTN) and PG&E National Energy Group

The large range in cost for transmission pipeline expansion, $300,000 to $4,200,000 per mile, was explained in terms of variations in size, terrain, and in the type of expansion, e.g. looping, added compression, etc. The description of the process for a transmission pipeline expansion project focused on showing a market for the added gas capacity, both to the Federal Energy Regulatory Commission (FERC) and to financiers. Commissioner Laurie questioned a possible need for mandated capacity expansion versus the current market-driven process to obtain more timely capacity expansions for power plants. Mr. Eisenmann indicated that the FERC might not make such a dramatic change in their approval process, but that it might be possible for California to undertake mandated pipeline projects. The time needed for the approval process varies from about six months to about two years for large projects with the environmental review being the critical path. Commissioner Pernell asked about allowance during construction for future expansion of pipeline capacity. Mr. Eisenmann indicated that it is common to allow for future capacity increase by pre-investment in pipeline steel to allow compression to be added as market demand grows. The current interstate system is not adequate to meet peak power plant demand. Even though there are no current pipeline expansion projects under construction, the Baja Norte project is scheduled for completion in 2002. There is a current open season process for determining the interest for adding more pipeline capacity to PG&E GTN's for delivering Canada's gas to California. Despite the limited delivery capacity of inter-state transmission, price signals are increasing drilling activity and interest in new pipeline concepts to access new gas resources, e.g., in Alaska and the MacKenzie Delta. Mr. Eisenmann concluded by stating that he hopes that the regulatory approval process will be streamlined and that he believes that a pro-rata curtailment is the best curtailment policy.

Dan Thomas, Pacific Gas & Electric Co., Director, Products & Sales, California Gas Transmission (representing PG&E Gas Transmission)

Eighty percent of the storage capacity of Pacific Gas and Electric (PG&E) Gas Transmission, smaller than that of Southern California Gas Company (SoCal Gas), is used primarily for the core market with the remaining 20% for non-core use. Current pipeline and storage capacity are not adequate to meet the non-core power generation demand in low hydro years, although it can still be met in average years. There is a need to increase backbone capacity to provide the needed deliverability to meet the growing power generation demand and to maintain slack capacity. Added storage capacity is also needed—the new Lodi facility is expected to be on-line in late 2001.. The Baja path that receives gas from the southwest will be very expensive to expand. On the other hand, the expansion of the Redwood Path, which receives gas from Canada, would be relatively inexpensive. However, the Redwood Path expansion will create stranded capacity unless there is also an expansion up north off PG&E Gas Transmission—Northwest.

Steve Watson, Southern California Gas, Capacity Planning Manager

SoCal Gas has adequate interruptible backbone capacity and storage capacity to reliably serve its core and non-core customers. Planned increases in pipeline supply backbone will further enhance supply reliability for customers in Southern California. SoCal forecasts of future power generation gas demand assumes that many proposed plants will not be built and that the gas demand for plants that are built will be at least partially offset by retirements of old power plants. SoCal Gas will consider expansions to the extent that shippers are willing to pay for them. The 1992-93 Wheeler Ridge expansion was “at risk” until 2000 when the California Public Utilities Commission (CPUC) allowed it to be rolled into SoCal’s rate structure. SoCal Gas is going to hold open seasons this year to solicit non-core customer interest in expansion of the redelivery system. SoCal Gas can provide the same level of firm service to a new power plant anywhere on the SoCal Gas system as for the existing non-core customers. Completion of new pipeline construction would take about one year after assurance of a long-term commitment necessary for the CPUC and financing are obtained. SoCal can deliver almost 800 MMcf/d to San Diego Gas & Electric (SDG&E), but SDG&E can only redeliver, at most 600 MMcf/d to its customers. To alleviate this constraint, SoCal is constructing a new pipeline to add 70 MMcf/d of low-cost redelivery capacity to SDG&E. This project, along with the Baja Norte project, should eliminate SDG&E’s curtailments of power plants. SoCal has not curtailed core or non-core customers for over ten years.

Craig Chancellor, Calpine, Gas Regulatory Manager

Calpine is securing its own natural gas reserves and production and suggests that California should explore liquefied natural gas (LNG) to increase its gas supply. The market for in-state California natural gas may be limited by gas quality issues that could be resolved by blending California gas with high British Thermal Unit (Btu)-content inter-state pipeline gas. Also, the time needed to enhance pipeline capacity to meet power plant needs should coincide with the timing for the power plant project.

PUBLIC COMMENT

Robert F. Williams, Williams Technical Associates, Inc., President

Mr. Williams questioned whether OPEC price signals affected the price of natural gas, possibly delaying pipeline projects by depressing gas prices, and the price elasticity of natural gas. Mr. Thomas and Mr. Chancellor commented on the first question, noting that the influence of OPEC on gas prices would depend on whether the gas was associated or non-associated. Mr. Wood and Mr. Chancellor commented on the price elasticity of natural gas noting that it would depend on how direct the link of the gas price was to the final paying customer of the product, e.g. electricity.

Steve Moore, San Diego County Air Pollution Control District

Mr. Moore noted to Mr. Watson that SDG&E began in June 2000 delivering up to 70 MMcf/d to a power plant at Rosarita Beach. The new SoCal Gas pipeline will offset this delivery. A new generation unit will begin operation in June 2001, requiring an additional 85 MMcf/d. Even with this new capacity curtailments are a significant possibility in San Diego County.

John Martini, California Independent Petroleum Association (CIPA)

CIPA is commissioning a gas elasticity study that they expect to show that California gas producers, given the proper incentives and regulatory relief, can tap into the 4 trillion cubic feet (Tcf) of on-shore and 21 Tcf of offshore California natural gas reserves and contribute to increasing gas supplies to power plants in California. Mr. Martini indicated that CIPA would be willing to provide a copy of the study when it was completed.

Barry Brunelle, Sacramento Municipal Utility District (SMUD)

Mr. Brunelle asked Mr. Chancellor if Calpine is considering an expansion similar to the Mojave Northwest expansion or some sort of intra-state expansion. Mr. Chancellor replied that they were considering expansions and are continuing to optimize their own proprietary pipeline system.

Azibuike Akaba, Communities for a Better Environment (CBE), Research Associate

Mr. Akaba asked if the quality of natural gas might be compromised, e.g. by allowing a higher sulfur content, in order to increase available gas. Mr. Watson answered that quality compromises were not necessary to increase gas supplies and that blending was used to maintain gas quality.

PANEL 2: CURRENT NATURAL GAS UTILITY CURTAILMENT POLICIES/PROCEDURES

Dan Thomas, Pacific Gas & Electric Co.

The need for gas curtailment typically occurs during extremely cold weather or due to accidental loss of supply, such as a pipeline rupture. Under conditions of inadequate gas supply, CPUC Rule 14 governs the process of remedies implemented by the utility to maintain gas supply to core, especially residential, customers. Operational Flow

Orders with associated penalties, used frequently by PG&E, then diversions, then curtailments are implemented. Mr. Thomas noted that the penalties for non-compliance with curtailment orders by non-core customers might not be large enough to force compliance, especially for power plants selling electricity at high prices.

New storage at Lodi will help avoid curtailments, as would the possible future storage expansion at Wild Goose. Other options might include alternate power plant fuels, currently not likely, and conservation, something PG&E is starting to examine in greater detail. Mr. Thomas concluded by making the following three points: (1) some form of backup fuel may be necessary/economic for power generators; (2) PG&E's system is not currently designed to provide firm service to both core and non-core customers; and (3) added capital investment is required to provide increased gas supply reliability or alternate fuels for power plants.

Mark Seedall, Duke Energy, Director of Electric Modernization

Duke energy owns the Moss Landing, Morro Bay and Oakland power plants in Northern California and operates the South Bay Facility in San Diego. The modernization of all these power plants would increase gas consumption by about 20%, while increasing power output by 40-50%, due to improved efficiency. The costs of such modernization projects requires that an adequate and reliable supply of natural gas is available. This is especially important because air emission regulations prohibit the use of alternate fuels, making modernized power plants completely dependent on natural gas. Commissioner Laurie asked about the costs associated with alternate fuels. He suggested that this issue needed more attention. Mr. Seedall indicated that alternate fuels would not be needed because California had sufficient pipeline and storage capacity. Mr. Wood asked whether the power plant or the gas utility would be responsible for gas storage. This lead to a general discussion of the appropriate assignment of responsibility for gas storage and related delivery capability. Mr. Seedall thought that curtailment rules should be changed to consider the reliability of the electric grid. He also thought that must-run and recently modernized power plants should be given some priority for gas supply.

Mohsen Nazemi, South Coast Air Quality Management District

Mr. Nazemi described South Coast bubble Rule 1135 for utility boilers and bubble Rule 1134 for gas turbines as they were used to reduce air emissions. This lead to emission trading that eventually caused the utilities to find it cheaper to use clean-burning natural gas than alternate fuels. In practice, no fuel oil is currently burned in the South Coast region. Only about one-third of the generation capacity, mostly older units, has air emission controls installed because it was cheaper to purchase credits. However, credits have become very expensive, tilting the cost advantage to controls for reducing air emissions. South Coast has directed is staff to propose changes to remove powerplants from the RECLAIM program, and apply best available retrofit emission control technologies (BARCT) to the powerplants. Once BARCT has been applied, the powerplant may be reintroduced to the RECLAIM program. Alternate fuels do not have much of a chance in this environment. Mr. Nazemi also indicated that electricity curtailment could lead to increased air emissions, citing battery plants as an example. Newer low-sulfur and low-nitrogen fuel oils might be considered, however.

Arden B. Walters, Advanced Energy Research, President (representing ASPEN)

An advantage of alternate backup fuels is that they provide for gas supply interruption due to accidental unplanned pipeline outages, not just for cold weather periods. In this way they provide an additional level of security that pipeline system design cannot. The cost of stored fuel will depend on the design curtailment duration. It could be only for a few cold morning hours, for a week of cold weather or pipeline outage, or for an entire season, as was the case some years ago in California when fuel oil was used extensively at many power plants during the winter months. The current experience with alternate fuels is largely limited to gas turbine peakers because the air emission controls for intermediate and base load combined cycles or boiler units can be fouled by the to use of alternative fuels. Typically the alternate fuel for gas turbine peakers was #2 distillate . Because peaker backup fuels are subject to long storage periods, the tendency of #2 distillate to decompose and clog fuel filters led some utilities to use slightly more expensive, but more stable, jet fuel. The pre-investment to meet the same air emission requirements as for natural gas when using such liquid backup fuels is going to be very high. It is unlikely that dry low-nitrogen oxide (NOx) burners can be made to work for the liquid fuels, requiring a very large over-investment in selective catalytic reduction (SCR) capacity. If alternate fuel backup systems are to be reliable, they must be run on a regular basis, further intensifying the air emission issue. Other options for gas turbine backup fuels include mini LNG storage, expensive, but without a significant air emission handicap, or propane-air, used extensively as a natural gas backup fuel in low-pressure burner applications. Any experience with the use of propane-air, or propane-air-natural gas blends in gas turbines would need to be investigated. In any case, the higher flame speed of the propane would probably cause a very great deterioration in the effectiveness of dry low-NOx burners.

PUBLIC COMMENT

Robert F. Williams, Williams Technical Associates, Inc., President

Mr. Williams suggested that in exchange for an uninterruptible gas supply, power plants supply a 10-20 day natural gas reserve, including a margin and compressor component. Mr. Thomas thought that the generators did have some responsibility for gas supply reliability and that the added cost of reliability should somehow be included in the price of their contracts. Commissioner Pernell inquired as to size of the required storage. Mr. Thomas indicated that the added storage would be provided by the expansion of an existing storage facility, citing a cost of about $75 million to increase injection and/or withdrawal capacity. Mr. Seedall indicated that a 7-day gas supply for a 500 megawatt (MW) combined cycle facility would be about ½ billion cubic feet (Bcf). Mr. Williams next suggested that a policy of power plant technology diversity might be a good idea. Mr. Seedall indicated that he could not imagine anything other than a natural gas power plant because of the environmental rules in California. Finally, Mr. Williams inquired about the exhaustion of emission credits. Mr. Nazemi replied that this was already happening in the South Coast.

Steven Moore, San Diego County Air Pollution Control District

Mr. Moore asked Mr. Nazemi if he had looked at the local impacts of burning alternate fuels, particularly sulfur oxides (SOx) and particulate matter (PM10). Mr. Nazemi replied that he had not because alternate fuels have not been a serious option.

Azibuike Akaba, Communities for a Better Environment, Research Associate

Mr. Akaba asked if there were any existing regulatory priorities for natural gas curtailment, especially residential vs. industry. Mr. Thomas replied that the curtailment order was power plants first, then industrial customers, ensuring gas supply to residential customers. Mr. Akaba next asked Mr. Nazemi if under the reclaim program there was a cap in the use of emission credits making it mandatory to install pollution control equipment. Mr. Nazemi said that there would probably be a minimum requirement for pollution control equipment, but that all the details of the RECLAIM program were not yet worked out.

Nancy E. Ryan, Environmental Defense

Ms. Ryan asked Mr. Nazemi if he knew of examples other than battery plants that would experience increased emissions due to electricity curtailment. Mr. Nazemi said that he thought refineries and other large industrial operations would require emergency plans to shut down for an electricity curtailment. Ms. Ryan asked Mr. Nazemi if a similar problem might occur for gas curtailments, e.g. for power plants. Mr. Nazemi replied that he didn't think so. Questioned if gas curtailment of power plants would result in increased emissions, both Mr. Nazemi and Mr. Seedall indicated that it might be possible in some situations, but that they were not sure.

Written Comments Received After the Workshop

Written comments were received from The Utility Reform Network (TURN), Calpine Corporation, and El Paso Natural Gas Company. The full text of their comments can be found at www.energy.ca.gov/siting/constraints/documents/comments/.

ANSWERS TO THE QUESTIONS RAISED IN THE COMMITTEE'S WORKSHOP NOTICE

Issue 1: The lack of available natural gas pipeline capacity may prevent the licensing of natural gas fired power plants in California.

A. *General Questions*

- *What is the approximate cost of building new pipeline capacity ($/Mile)? How does size and location of the pipeline affect the cost?*
- *What are the steps needed to add new pipeline capacity?*
- *Who is in charge of making the decision to seek new pipeline capacity? Who has the responsibility of providing the final approval?*
- *Describe the federal and state regulatory processes for approving pipeline projects?*

- *How long does it take to construct a new pipeline project, once approved by a regulatory body? What about an expansion project?*
- *Who has the authority to insure that new natural gas infrastructure is available to meet power plant needs at the federal and state levels?*

Eric Eisenman summarized the process as follows (Kirk Morgan also gave a similar summary of the process):

1. Open season
2. Cost estimation
3. Establish market commitment
4. FERC application
5. FERC approval
6. Acquire materials (turbines & pipe)
7. Obtain state and federal right of way grants
8. State and local permitting
9. Financing
10. Construction
11. In service

The first step in the process of building new inter- or intra-state natural gas capacity is to identify the need for new capacity. There is no state or federal planning process to forecast demand for natural gas and identify the need for new transmission or storage capacity needs. Currently, natural gas suppliers will identify the potential need for capacity additions, and if they believe conditions warrant investigation they will conduct “open seasons” to identify interest in developing new pipeline capacity. Based on the results of the open season, the natural gas suppliers can demonstrate the market need and start to seek financial and regulatory approval. Route selection and environmental review would also add to the time necessary for approval of the expansions. Early identification of both inter- and intra-state pipeline capacity needs to service new powerplant facilities is critical to ensuring that capacity is available when needed. FERC has approval authority for inter-state pipeline capacity projects and the CPUC has approval authority for intra-state projects. Eric Eisenman described the FERC approval process as follows:

1. Application
2. Land owner notification
3. Federal register notice
4. Interventions and protests
5. Scoping and public outreach meetings
6. Preliminary determination (non-environmental issues)
7. Draft EIS/EA
8. Final certification

The time it takes to approve new pipeline capacity varies depending on the type, length of pipeline, location and environmental and regulatory issues that need to be address. New pipeline approval will likely take 1 to 2 years, and increasing capacity by adding additional compressor stations will likely take much less time. The time necessary for construct of new pipeline capacity also vary depending on type, length of pipeline and location. Estimates range of from months to years for the construction times for new pipelines and expansions.

Mr. Eisenmann estimated the cost to range from $300,000 to $4,200,000 per mile depending on the size of the pipeline, terrain, and the nature of the new pipeline capacity (e.g., added compression versus adding new pipelines). Mr. Edward O'Neill estimated the costs for a 30-inch pipeline to range of from $700,000 per mile, in relatively uninhabited desert, to $2,000,000 per mile for more densely populated areas with significant numbers of road crossings.

B. *Questions Related to the Interstate Pipeline System*

- *Is the current interstate natural gas pipeline system serving California adequate to meet existing power plant natural gas demand on a peak month basis?*

  The adequacy of the interstate pipeline system is depended on which natural gas supplier is being examined. The SoCal Gas system is conditional adequate, but the PG&E and SDG&E system require some upgrades. Storage capacity is another issue requiring examination.

- *Are adequate steps being taken to insure that natural gas will be available for future electric generation facilities when the supply is needed?*

  There is no state or federal planning process to forecast demand for natural gas and identify the need for new interstate transmission or storage capacity needs. While some steps are being taken, there was no assurance that adequate steps to ensure the natural gas supply for future power plants in all parts of California are or will be taken.

- *What pipeline projects are currently under consideration to increase capacity to the California border?*

  The projects include:

  - PG&E GT-NW - 200 MMcf/d, in open season
  - Kern River - 126 MMcf/d before FERC
  - Southern Trans – 90 MMcf/d FERC approved
  - El Paso All American Pipeline conversion from oil to natural gas – 500 MMcf/d

- *How much interstate pipeline capacity to California is dedicated to electric generation in the state? Who are the capacity holders? What is done with capacity that is not utilized?*

Kirk T. Morgan provided some information on the powerplants that are served by the Kern River Gas Transmission Company. Dan Thomas provided information that indicated the portion of PG&E GTN's capacity devoted to power production to be 42 percent. Copies of these presentations are on the Energy Commission's web site at www.energy.ca.gov/siting/constraints/documents.

C. *Questions Related to the Instate Pipeline System*

- *What is the current level of pipeline capacity installed in California? Please specify by region or entity to the extent possible.*

  The capacity of the California intra-state gas transmission pipeline system was addressed by a number of the panel members, which can be found at www.energy.ca.gov/siting/constraints/documents. Published sources can be used to obtain reasonable estimates that can be verified by the pipeline owner/operators. No information on gas supply reliability enhancing system interties was provided.

- *What pipeline projects are currently under consideration to increase capacity inside California?*

  Information on currently considered projects was provided, but there was no indication if this information is complete. Project included:

  - PG&E - 200 MMcf/d in Redwood Path likely to occur due to need and low costs
  - PG&E - 200 MMcf/d in Baja Path, questionable to to expense
  - SCG – 70 MMcf/d to SDG&E

- *What are the current storage capacity levels in California? What expansion plans are being considered in California, if any?*

  Information was provided on both current storage capacity and storage expansion plans, but detailed information on capacity and deliverability was not provided.

- *Is the current natural gas utility pipeline system adequate to meet existing and future power plant natural gas demand on a peak demand day? If not, explain the inadequacies and possible steps to mitigate them.*

  This question was answered for SoCal Gas (yes) and PG&E and SDG&E (no). While PG&E explained their inadequacies and suggested some possible steps for mitigation, there was little indication if such steps would be adequate. SDG&E indicated that currently planned pipeline expansion may reduce their inadequacy.

- *Suggest ways that California's natural gas production might be stimulated to play a greater role in meeting future power plant generation needs.*

  A number of presenters suggested that increased California in-state gas production would be a great help, there was little offered as to how to accomplish this, except for blending as a strategy. Mr. Chancellor did suggest that gas quality specifications might limit the take of in-state California gas. He suggested that some gas blending might make California gas more marketable. Mr. Martini offered to share CIPA's natural gas elasticity study with the Energy Commission.

Issue 2: Current natural gas utility curtailment policies affect supply of natural gas to power plants during peak demand periods.

- *What are curtailment rules outlined for the investor-owned utilities regulated by the CPUC and entities not regulated by the CPUC?*

  Mr. Thomas, in particular, provided a detailed explanation of curtailment rules under the CPUC. See is a copy of Mr. Thomas presentation at www.energy.ca.gov/siting/constraints/documents. Major federal reallocations and curtailments of natural gas were not covered.

- *In general, describe the curtailment priority process by region to the extent* possible.

The curtailment priority process by region was not covered in detail. Different curtailment rules apply to each gas utility. PG&E's Rule 14 was discussed by Mr. Thomas. He indicated that PG&E has a unique gas diversion process, agreed to by customers and adopted by the CPUC in 1997.

- *What fuel alternatives do generators have when natural gas supply is limited*?

  Air emission regulations in Southern California, and most of the rest of California, do not currently allow for the use of most backup fuels commonly used by power plants elsewhere. Significant added investment in air emission controls may allow such fuels as #2 distillate and/or jet fuel to be used for California gas turbine power plants, but the capital and operating costs would be expected to be very high. Newer low-sulfur and low-nitrogen fuel oils were suggested by Mr. Nazemi as a possible alternate power plant fuels. An analysis the costs of using alternate fuels could be useful in resolving this issue.

- *What changes to the present curtailment policies, if any, are recommended in the current market environment?*

  In general, power generator presenters felt that their gas should not be curtailed, while gas supplier presenters indicated that curtailment of non-core power plant customers might be needed to maintain reliable service to core customers. Mr. Seedall thought that curtailment rules should be changed to consider electric grid reliability and that must-run and recently modernized power plants should be given priority for gas supply. This issue requires further analysis.

- *Is it in the best interest of California's citizens to have power plants subject to curtailment? If so, under what circumstances?*

  Mr. Thomas, in particular, noted that having natural gas and no electricity to power fans/blowers greatly reduces the usefulness of the gas. It can be concluded that power plants subject to gas curtailments that will shut down or reduce the plant operations are not in the best interest of California citizens. If alternate fuels are available to keep the power plant operating, the adverse impact of the gas curtailment is eliminated. This implies a lot of conditions being met by the alternate fuel capability, including meeting environmental regulations and, usually, fuel switching while operating. Stored natural gas would meet these conditions if it could be delivered at adequate throttle pressure to the power plant.

- *To alleviate the possibility of curtailing electric generation, are there any alternatives, such as the use of an alternative fuel, that new electric generation facilities should be required to maintain on-site? What alternative fuel options should be considered?*

  In other parts of the U. S., with less restrictive air regulations, stored fuels are commonly used to compensate for natural gas curtailments at power plants, including gas turbines and combined cycles. Either #2 distillate or jet fuel are the most common fuels stored on-site for gas turbines. On-line fuel switching is possible if this capability is built into the gas turbines. Small-scale LNG storage has been demonstrated, but is expensive. Propane, mixed with air, is a long-proven natural gas backup option that works in most low-pressure burners, but might not perform well in gas turbines, especially regarding air emissions.

- *How may the need for clean air be balanced with the need to insure that there is a stable and reliable supply of electricity to meet California's needs?*

  This issue requires more examination. Both the use alternate backup fuels and the operation of added, or expanded, storage facilities would be expected to add to air emissions.

- *Is there any potential value in curtailing electricity use to reduce natural gas curtailment? If so, what should be the decision process and who should implement it?*

  This issue requires additional analysis.

STAFF RECOMMENDATIONS BASED ON WORKSHOP DISCUSSIONS

1. There is no state or federal planning process to forecast demand for natural gas and identify the need for new inter- and intra-state transmission or storage capacity needs. The Energy Commission should develop and disseminate information on expected future demand for natural gas and potential locations for future powerplant development to improve market efficiency. The Energy Commission should also encourage potential power plant proponents to develop interest in natural gas supplies for their proposed facilities early in the powerplant permitting process.
2. Examine the option of mandated natural gas supply and storage expansions and transmission for meeting California power plant gas requirements in a more timely manner.
3. Analyze the costs and environmental aspects of using alternate backup fuels during gas curtailment at power plants.
4. Identify and analyze ways to increase in-state natural gas production. A major issue is finding more economical ways to blend lower Btu-content California natural gas with inter-state pipeline gas to meet pipeline quality standards.